

Decision 06-07-030 July 20, 2006

**BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA**

Order Instituting Rulemaking Regarding the  
Implementation of the Suspension of Direct  
Access Pursuant to Assembly Bill 1X and  
Decision 01-09-060.

Rulemaking 02-01-011  
(Filed January 9, 2002)

**OPINION REGARDING DIRECT ACCESS AND  
DEPARTING LOAD COAST RESPONSIBILITY  
SURCHARGE OBLIGATIONS**

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## **OPINION REGARDING DIRECT ACCESS AND DEPARTING LOAD COAST RESPONSIBILITY SURCHARGE OBLIGATIONS**

### **I. Introduction**

By this decision, we resolve various outstanding issues relating to the cost responsibility surcharge (CRS) methodology and the level of undercollections applicable to Direct Access (DA)<sup>1</sup> and Municipal Departing Load (MDL)<sup>2</sup> customers within the service territories of the investor-owned utilities (IOUs): Pacific Gas & Electric Company (PG&E), Southern California Edison Company (SCE), and San Diego Gas & Electric Company (SDG&E).

We adopt updated DA CRS undercollection balances as of December 31, 2005, based upon the consensus reached by the interested parties, and resolve issues concerning the process to determine CRS obligations on a prospective basis.

The Commission, in D.02-03-055, suspended DA for new contracts executed after September 20, 2001, but permitted preexisting DA contracts to remain in effect, on the condition that bundled utility customers

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<sup>1</sup> DA load customers purchase electricity from an independent electric service provider, and receive only distribution and transmission service from the utility. “Bundled” customers, however, rely on the utility for all these services. Therefore, distribution and transmission charges are “bundled” with a charge for the procurement of energy supplies.

<sup>2</sup> Departing Load (DL) **generally** refers to retail customers who were formerly IOU customers but now receive energy, transmission and distribution services from publicly owned utilities, self-generation or other means. Municipal Departing Load (MDL) refers to departing load served by municipal utilities and irrigation districts, as defined in Pub. Util. Code § 9604(d)), for which a CRS applies pursuant to D.03-07-028 and related Commission orders. Unless otherwise stated, all statutory references are to the Public Utilities Code.

would not be adversely impacted.<sup>3</sup> Specifically, we required that bundled customers be indifferent due to customers migrating from bundled to DA load, and that there be no cost shifting. To prevent cost shifting, we adopted a methodology in D.02-11-022 to capture the relevant costs in the form of a CRS to be assessed on designated DA load. The CRS incorporates, among other elements, a California Department of Water Resources (DWR) power charge and the ongoing competition transition charge (CTC).<sup>4</sup> The CRS measures the change in total portfolio costs attributable to serving customer load that migrated from bundled to DA status (known as DA-in/DA-out modeling).

We previously resolved certain issues concerning the methodology for the DA cost responsibility obligations in D.05-01-040, which adopted CRS obligations for 2001-2003. In the instant order, we update the level of CRS undercollections through December 31, 2005, and adopt revised measures for determining CRS obligations prospectively.

By ruling dated March 30, 2005, the Administrative Law Judge (ALJ) prescribed a process to develop the record to true up CRS obligations for 2003

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<sup>3</sup> We suspended DA pursuant to legislative directive, as set forth in Assembly Bill No. 1 from the First Extraordinary Session (AB 1X). (Stats. 2002, 1<sup>st</sup> Extraordinary Sess., ch. 4.) AB 1X was enacted to respond to the serious situation in California when PG&E and SCE became financially unable to continue purchasing power due to extraordinary and unforeseen increases in wholesale energy prices. DWR assumed responsibility for acquiring power supplies on behalf of the IOUs' retail end use customers.

<sup>4</sup> The purpose of CTC is to recover the costs authorized by § 367(a)(1) – (6). These costs include power acquired from third parties under contracts that were in effect on December 20, 1995, at a price that exceeds the current market price of electricity and qualifying facilities (QF) restructuring costs.

and to compute updated CRS forecasts for 2004 and 2005.<sup>5</sup> A “Working Group” was formed for this purpose, overseen by the Commission’s Energy Division, and representing various parties’ interests involved, to engage in consensus building. The “Working Group” consisted of the IOUs, parties representing DA customers,<sup>6</sup> parties representing MDL customers,<sup>7</sup> and consumer groups, *i.e.*, Division of Ratepayer Advocates (DRA)<sup>8</sup> and The Utility Reform Network (TURN). DWR also participated by providing modeling support through its consultant, Navigant, Inc. While the Working Group reached consensus on several issues relating to CRS obligations, particularly for DA customers, parties did not reach agreement on a number of issues relating to the derivation of MDL CRS obligations.

By ruling dated February 23, 2006, the ALJ formally incorporated into the record in this proceeding the “Final Report of the Working Group to Calculate the CRS Obligations Associated with Municipal Departing Load and Direct Access.” (Report.) The ruling also incorporated a February 15, 2006, letter to the assigned ALJ and from PG&E, SCE, and Municipal Departing Load

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<sup>5</sup> The calculations made for CRS obligations for 2004 were made on a “forecast” basis, utilizing data consistent with the forecast DWR revenue requirement adopted for the year 2004.

<sup>6</sup> DA load interests were represented by Alliance for Retail Energy Markets (AReM), California Large Energy Consumers Association (CLECA) and California Manufacturers & Technology Association (CMTA).

<sup>7</sup> MDL interests were represented by the California Municipal Utilities Association, City of Corona, City of Rancho Cucamonga, Hercules Municipal Utility, Merced and Modesto Irrigation Districts, South San Joaquin Irrigation District, Turlock Irrigation District, and Northern California Power Agency.

<sup>8</sup> At the time the Report was issued, DRA was known by its previous name, the Office of Ratepayer Advocates.

parties. The letter clarified parties' positions with respect to certain of the recommendations set forth in the Report. Parties were also provided an opportunity to file comments on the Report. Opening comments were filed on March 8, 2006 with reply comments filed on March 17, 2006. No evidentiary hearings were required. These materials constitute the record that forms the basis for the instant order.

## **II. Issues Relating to DA CRS Obligations**

### **A. DA CRS Undercollection Balances as of December 31, 2005**

#### **1. Parties' Positions**

Parties reached a consensus on the level of DA CRS undercollection balances as of December 31, 2005, even though they disagreed as to the appropriate underlying market benchmark methodology to calculate the CRS undercollections. Under the CRS "indifference" methodology, a market benchmark is used to calculate the hypothetical cost of power that the IOU would have incurred if DA load had continued to take bundled service (*i.e.*, a "DA-in" modeling scenario). The incremental costs attributable to changes in DA load forms the basis to derive bundled customer "indifference."

Parties recognize that it would be difficult and time-consuming to litigate different hypothetical market benchmark approaches. Protracted litigation would increase business uncertainty and delay finalizing CRS obligations. Accordingly, while disagreeing on the underlying methodology, the parties reached a compromise agreement on end-of-year 2005 CRS undercollection balances for PG&E and SCE. Parties agree that the end-of-year 2005 CRS undercollection balance for SDG&E is zero.

Parties reached a compromise to agree on a DA CRS undercollection for PG&E of \$30 million as of December 31, 2005, and also reached consensus

that PG&E's undercollection is \$30 million for DWR bond charge recovery, applicable to DA customers as of the end of 2005. Parties also reached a compromise to agree on a DA CRS undercollection balance of \$522 million for SCE as of year-end 2005. Parties also agreed to an undercollection of \$55 million for the DWR bond charge applicable to SCE.

Parties' calculations of PG&E's end-of-year 2005 CRS balance range from a \$140 million overcollection (based on the Market Price Referent (MPR) model)<sup>9</sup> to a \$156 million undercollection (based on the model currently in effect, utilizing spot purchase and sales prices). The parties likewise calculated a range of DA CRS undercollection levels for SCE as of year-end 2005, from \$357 million to \$552 million. The \$357 million figure, offered by CMTA, CLECA, and AREM was based on a benchmark utilizing the MPR model with provision for "negative" indifference. The \$552 million undercollection balance was based on the currently used benchmark based on spot purchase and sales prices.<sup>10</sup>

PG&E and SCE proposed benchmarks that would place the year-end 2005 undercollection balances within this range. Parties disagreed as to the capacity costs that would have been incurred on a "DA-in" basis for those historic periods. Each utility acknowledged, however, that some capacity-related cost above the cost of spot purchases and sales should be reflected in the benchmark.

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<sup>9</sup> The MPR model was developed and reviewed in the Renewable Portfolio Standard proceeding (Rulemaking (R.) 04-04-026) and adopted in D.04-06-15 and Resolution E-3942. The MPR model was used in the calculation of the CTC benchmark in PG&E's 2006 Energy Resource Recovery Account (ERRA) proceeding. (Application (A.) 05-06-007, D.05-12-045.)

<sup>10</sup> The Tables in Appendix 2A and 2B of this order show the undercollection results for PG&E and SCE based on different benchmark methodologies.



## **2. Discussion**

Parties' consensus as to year-end 2005 DA CRS balances are within the middle range of values calculated by DA customer parties versus TURN and ORA, and are within the range calculated by PG&E and SCE. We approve the consensus reached on these undercollection figures. Thus, we adopt as a reasonable figure for the PG&E end of year 2005 DA CRS undercollection balance, of \$30 million plus the DWR Bond Charge balance of \$30 million. We also adopt, as a reasonable outcome, the consensus end-of-year 2005 DA CRS undercollection for SCE of \$522 million, and the DWR Bond Charge undercollection of \$55 million, to be recovered from DA customers. We conclude that the compromise reached by parties reasonably balances the differing interests involved.

### **B. Prospective DA CRS Market Benchmark Methodology Revisions**

#### **1. Parties' Positions**

Parties representing DA customers assert that the current CRS market benchmark, which is based solely on spot market purchases and sales of surplus power, is unduly cumbersome, administratively difficult and slow to provide predictions of the indifference charge. DA parties express concern that under the current methodology, the DWR power charge component of the DA CRS cannot be determined in a timely manner, in part because of the need for true up after the fact. Parties are left without information concerning the level of CRS applicable to their current consumption. The current method also relies on utility power purchase and sales data which the utilities view as confidential and proprietary. Thus, relevant data are not made available to many of the parties that are responsible for paying CRS. The DA Parties propose that

the current methodology be revised so that customers can know their CRS liability on a current basis.

Participants in the Working Group discussed alternative methodologies, and to what degree any changes in methodology should be made prospectively. The Working Group reached agreement on a benchmark based on published futures prices to replace the weighted average spot purchase and sales benchmark used in previous CRS model runs. The Working Group recommends that the benchmark be revised annually based on an average of one-year strip power futures quotes for “North Path” (NP) 15 and “South Path” (SP) 15 for each calendar year as published in the *Megawatt Daily* periodical.<sup>11</sup>

Parties propose that for purposes of determining the indifference charge for 2006, the average of cost quotes for one-year strips of power be taken during the period November 15 through December 15.<sup>12</sup>

Parties also agree that a Resource Adequacy/Generation Capacity (“RA/capacity”) cost adder should be incorporated for each IOU,<sup>13</sup> based on the annual capital costs for a combustion turbine generator. The Parties negotiated RA/Capacity adders in developing the agreed-upon 2005 year-end undercollection balances.

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<sup>11</sup> A second alternative approach to deriving the benchmark was discussed based on one-year forward prices for natural gas at Henry Hub, converted to electricity prices using the methodology for calculating the MPR. The benchmarks estimated in this fashion were \$55.5/MWh in 2003, \$60/MWh for 2004 and \$66.4/MWh for 2005.

<sup>12</sup> The power costs reflect a 6 X 16 product, and the price will be multiplied by a factor of 0.87 to convert the power cost to a 7 X 24 product price.

<sup>13</sup> SDG&E prefers a gas futures-based benchmark and has not yet determined whether it will agree to a power futures-based benchmark.

Parties also negotiated RA/Capacity adder values for 2006, since there is no RA/Capacity market available at the present time to provide transparent values.<sup>14</sup> For years after 2006, parties propose that the cost quotes for one-year strips be gathered for the period October 1 through October 31 of the preceding year to facilitate timely filings by the utilities. The power costs would be differentiated as between NP 15 and SP 15, and applied to each IOU. These benchmarks are to be grossed up for line losses.

The resulting 2006 market benchmarks developed by the Working Group for the DA non-exempt customers' CRS obligations are \$90.12/MWh (\$95.52 at the meter) for PG&E and \$95.17/MWh (\$100.22 at the meter) for SCE. These benchmarks represent the 30-day average, over the period from November 15, 2005 to December 15, 2005, of 12 month forward prices for 2006 at NP 15 and SP15, respectively.

Parties agreed to apply this market benchmark methodology for prospective CRS calculations beginning in 2006 for PG&E and SCE, but differed with respect to application of the revised methodology to prior periods. TURN and ORA, in particular, opposed applying the revised benchmark methodology to past periods. With regard to SDG&E, parties agreed that since its undercollection balance was paid off in 2005, there is no need for further

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<sup>14</sup> RA/capacity adders for 2006 were negotiated as part of on-going workshop report discussions. Proposals have ranged from approximately \$1.20/MWh-\$9.60/MWh. The lower value of this range is based on PG&E's proposal to use the going-forward fixed cost needed to maintain a specific 300 MW steam unit on the PG&E system net of the energy benefit received from this unit. The higher value is based on CLECA, CMTA, and AReM's proposal to use the annual carrying cost of a combustion turbine.

discussion of methodological changes for the 2003-2005 period applicable to SDG&E.

## **2. Discussion**

We conclude that the proposed revision in the benchmark methodology to utilize futures-based prices offers advantages over the existing process. The existing benchmark may also understate relevant costs under a variety of market conditions, whereas the revised benchmark more accurately incorporates firm power costs and capacity charges. The need for a RA/capacity value was acknowledged in the Commission's white paper on RA/capacity markets ("California Public Utilities Commission Capacity/Resource Adequacy Markets White Paper," issued August 25, 2005). Such an adder also recognizes the cost of complying with resource adequacy requirements.

The revised benchmark offers the following advantages:

- ***Reflects procurement practices.*** A futures-based benchmark reflects current resource adequacy requirements better than model-derived market prices, after-the-fact spot prices, or administrative values from other proceedings. Resource adequacy requirements dictate that the IOUs have 90% of their power forward-contracted or self-supplied a year in advance and rely on spot power for no more than 5% of their resources. The futures market provides publicly available estimates of the price the IOU would have to pay to serve DA/DL customers.
- ***Minimizes the need for after-the-fact true-ups.*** The forecasted value of utility and DWR resources will be measured against the benchmark, whether separately or combined. Any difference between these forecasts and actual costs will be accommodated via balancing accounts in the ERRA or DWR Revenue Requirement proceedings, and will not require separate true-up. The benchmark

itself can be set at the beginning of the year and not be subject to change. If drastic conditions occur that would prompt significant changes to the CRS market price benchmark, such a modification could be requested.

- ***Provides Transparency.*** Published futures prices provide transparency. All interested parties will be able to verify the benchmark value, avoiding the problems otherwise faced by parties who have been precluded from reviewing confidential utility data where the benchmark is based on utility activity in power markets.
- ***Promotes Simplicity.*** Using published forward prices, with minor adjustments, is simple, easily verifiable, and avoids using complex models or calculations that are not transparent to establish a market price benchmark.

Based on these considerations, we find the proposed revised benchmark methodology reasonable and hereby adopt it.<sup>15</sup>

We adopt the Working Group proposal to incorporate the revised benchmark methodology, as discussed above, in the CRS calculation of bundled customer indifference prospectively, beginning with calendar year 2006. Each utility's total power portfolio costs (in cents/kilowatt-hour (kWh)) including both utility retained generation (URG) power and their allocated DWR power costs will be compared to a market price benchmark comprised of the cost of a one-year strip of power plus a RA/capacity adder, as described above.

The DA CRS obligations for 2006 shall incorporate a share of the 2006 DWR revenue requirement adopted in D.05-12-010. The 2006 revenue

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<sup>15</sup> A detailed description of the adopted benchmark methodology is set forth in Appendix 1 of this order.

requirement for “old world” resources is the amount adopted in the utilities’ 2006 ERRR proceedings and/or in the most recent base revenue requirement proceeding.<sup>16</sup> The sales forecast used to determine the direct access non-exempt customers’ share of these costs will be the sales forecast presented in the utilities’ 2006 ERRR proceedings, as modified in the 2006 Annual Electric True-Up (AET), for PG&E. The AET is an advice letter process in which PG&E consolidates revenue requirements authorized on January 1 of the following year (*see* Resolutions E-3906, E-3956 addressing the rate changes effective January 1, 2005, and 2006, respectively). Thus, we clarify that the only modifications to the ERRR sales forecast that PG&E may make in its AET advice letter must have been previously authorized by a Commission order. If the 2006 DWR revenue requirement or utilities’ 2006 ERRR/Ongoing CTC revenue requirement is modified, then the calculations described above shall be likewise modified to reflect such changes.

For 2006, we adopt parties’ consensus for a RA/capacity cost adder of \$8/MWh for SCE and \$4/MWh for PG&E, which will be added to the average strip price.

The utilities shall file an advice letter prior to the end of each year or update testimony in their ERRR proceedings to reflect such indifference charge in the CRS adopted for the subsequent year. It is difficult now to predict appropriate levels for the cost of RA/capacity for future years.

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<sup>16</sup> SCE agreed to file an advice letter to update the DA CRS calculation following the issuance of a final general rate case (GRC) Phase 1 decision if that decision results in a change in the generation revenue requirement of more than 2% from that reflected in the current calculation. A similar 2% update rule shall apply to future changes in the IOUs’ generation base revenue requirements.

The Working Group agrees to reconvene in August 2006 to discuss RA/Capacity adders to be proposed for 2007 and beyond based on publicly reported transactions in a California RA/capacity market or other suitable public index once available. The issue of a suitable adder to reflect RA/capacity value will be revisited for 2007 and beyond as warranted by progress in developing transparent and publicly reported values for RA/capacity. We adopt this proposal and authorize the Energy Division to coordinate and arrange, as necessary, for the Working Group to reconvene within 30 days of this order to address RA/capacity adders, as noted.

**C. Use of Uniform Benchmark  
for Ongoing CTC and DWR Components**

**1. Parties' Position**

The Parties agree that the Commission should apply a consistent benchmark among each of the IOUs in the treatment of both the ongoing CTC and DWR power charge components. The Parties agreed on a modified methodology to calculate ongoing CTC and DWR Power Charge components of the DA CRS after 2005 with specific market benchmark figures used for DA CRS calculations.

Pursuant to D.03-07-030, the ongoing CTC component of the CRS is determined in the IOUs' annual ERRRA proceedings. Ongoing CTC consists of "old world" URG resources as specified in Pub. Util. Code § 367(a)(1) - (6) in calculating above-market costs.<sup>17</sup> Parties have referred to this as the "statutory approach" for calculating ongoing CTC.<sup>18</sup>

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<sup>17</sup> "Old World" URG refers to contracts and generation resources acquired prior to January 1, 2003. "New World" URG, by contrast, refers to contracts and generation

*Footnote continued on next page*

DA load that is not required to pay a DWR power charge is responsible for paying ongoing CTC.<sup>19</sup> For DA load responsible for paying a DWR power charge, however, ongoing CTC is blended with the combined effects of DWR and URG sources of power. Regardless of the blended indifference charge amount, the ongoing CTC component is the same as for DA load not responsible for paying the DWR power charge. However, if the ongoing CTC component is higher, the DWR power charge will be lower by an offsetting amount, and vice versa. In D.02-11-022, this was referred to as the “total portfolio method” for calculating the CRS indifference component.

The benchmark used in the calculation of ongoing CTC has been based on the levelized cost of a combined cycle turbine. By contrast, the benchmark for calculating the CRS indifference charge has been the IOU’s weighted average price of spot purchases and surplus sales. Under the total

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resources acquired by the IOUs since January 1, 2003, when they resumed responsibilities, previously held by DWR, for power procurement.

<sup>18</sup> Prior to their 2006 ERRR/ongoing CTC proceedings, both PG&E and SCE had incorporated the CRS indifference calculation for URG adopted in D.02-11-022 in their annual ongoing CTC revenue requirement. Under this approach (referred to by parties as a “total portfolio” approach), all “old world” IOU resources were included in the above market cost calculation, not just the ongoing CTC costs covered under § 367(a)(1) – (6). The Commission approved the inclusion of the CRS indifference charge in PG&E and SCE’s 2004 and 2005 ongoing CTC revenue requirement. However, in response to allegations by parties that the Commission had adopted two “methodologies” for calculating ongoing CTC, the Commission ordered that only ongoing CTC be included in future IOU ERRR/ongoing CTC revenue requirement applications. (See e.g., D.05-12-045 and D.06-01-035.) Thus, to eliminate any future misunderstanding, we note that “statutory CTC” is the same as “ongoing CTC” and does not represent one of several ways to calculate ongoing CTC.

<sup>19</sup> In D.02-11-022, that portion of DA load that had been continuously on DA status prior to February 1, 2001 was not required to pay a DWR Power Charge.



portfolio method as adopted in D.02-11-022, the CRS incorporates “above-market” URG costs in excess of a designated market benchmark. Both DWR and URG sources of power are recognized in computing DA cost responsibility for a power charge. The DWR power charge component of the DA CRS is the residual between the indifference charge and the ongoing CTC component.<sup>20</sup>

Working Group members agree that the market price benchmark should be applied consistently across all relevant CRS components (*i.e.*, both for ongoing CTC and DWR power charges). SDG&E, however, is concerned with additional cost shifting to bundled customers should the market price benchmark be used to determine the ongoing CTC in SDG&E’s 2006 ERRR filing. SDG&E thus recommends that the market price benchmark be applied to the DA CRS calculation for 2006, but not to SDG&E’s ongoing CTC calculation in its 2006 ERRR filing. PG&E’s 2006 ongoing CTC has already been set in the 2006 ERRR filing and is not intended to be modified.

## **2. Discussion**

We shall adopt the approach, as proposed above by the Working Group, for calculating ongoing CTC, applying a uniform methodology for all components of the CRS. For 2006, the ongoing CTC calculation shall employ the benchmark based upon the MPR model set forth in SDG&E’s and PG&E’s 2006 ERRR filings. The ongoing CTC is based on forecast costs, providing for accruals of under- or over-collections in utility ERRR accounts attributable to the cost of resources reflected in the ongoing CTC calculations as

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<sup>20</sup> See computational example in Appendix 1A, as prepared by DL parties. No other Working Group participants have disputed its accuracy.

well as other costs of “old world URG” at the end of each year.<sup>21</sup> Under or overcollections are reflected in the calculation of the DWR Power Charge and ongoing CTC components of the DA CRS in the following year. The DWR revenue requirement allocations to the IOUs already includes the true-ups from prior years, so no explicit adjustment is necessary. The modified approach will be simpler, more transparent, less cumbersome, and will use the same benchmark to calculate ongoing CTC.

**D. Treatment of “Negative” Indifference Charges**

**1. Parties’ Positions**

Another issue with respect to ongoing CTC involves the question of how to treat “negative” indifference charges, and the extent to which any such “negative” charge should be offset against positive undercollections to reduce overall charges.

The parties agree that the ongoing CTC adopted in PG&E’s ERRR proceeding should be used in conjunction with the indifference calculation. The DWR power charge component of DA CRS will thus be the residual of the Indifference Charge less the ongoing CTC. In PG&E’s service territory, the DA non-exempt customers’ share of the indifference amount is their proportion of the above market component of the sum of (1) PG&E’s 2006 DWR Power Charge revenue requirement plus (2) PG&E’s old world generation.

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<sup>21</sup> If the decision in an IOU’s GRC or similar base revenue requirement proceeding changes that utility’s generation revenue requirement by more than 2% in mid-year, the utility shall file an advice letter to update the DA CRS to reflect that change in generation base revenue requirement. This adjustment is necessary because generation base revenue requirements are not trued up to actual costs in the same manner as ERRR and DWR costs.

The ongoing CTC will be used in the indifference charge calculation for SCE in the same manner as for PG&E, with the following exception: In the event the benchmark in a given year exceeds the level of SCE's total portfolio power cost for that year, and to the extent there remains a DA CRS undercollection balance, the negative indifference charge shall be reflected in calculating the accruals to the undercollection balance for such year. Because non-exempt DA customers in SCE service territory are subject to a much larger CRS undercollection than DA customers in the other territories, the parties agree that any negative indifference charge that may occur for SCE should offset any existing DA CRS undercollection.

## **2. Discussion**

We conclude that parties' proposed treatment of negative indifference charges is reasonable and hereby adopt it. Once the existing CRS undercollection is eliminated, the indifference charge for non-exempt DA customers shall *not be* permitted to decrease below zero, and no negative balance should be carried forward. In no event shall such a negative indifference charge result in any net payment to customers who have left utility service. However, any accumulated negative indifference amount shall continue to be tracked and applied to any future positive indifference amounts that may accrue in later years of the applicability of the DA CRS. This approach is consistent with D.05-12-045, which permits a negative ongoing CTC to offset a subsequent positive ongoing CTC.

SCE shall track accruals to the CRS undercollection balance and file an advice letter in anticipation of such balance reaching zero to reduce the CRS to the level dictated by the remaining individual CRS elements. Given the parties agreement on the end of year 2005 undercollection balance, with the balance

reaching zero by June 2006, PG&E will not be required to track the undercollection balance thereafter.

**E. Billing Adjustments Between Core and Noncore Bundled Customers**

**1. For PG&E Customers**

**a. Parties' Position**

Another issue to be resolved involves the proper billing adjustments to “core” (*i.e.*, small bundled customers) versus “noncore” (*i.e.*, large industrial bundled customers) attributable to their past respective contributions toward CRS obligations. Since implementation of the PG&E bankruptcy settlement rates in March 2004, noncore bundled customers have contributed excess revenues to fund the CRS undercollection “loan” estimated in the amount of \$325 million. The \$325 million excess payments benefited core bundled customers through lower power charges.

Effective January 1, 2006, with the implementation of the Phase 2 bundled rates in PG&E’s 2003 GRC, the CRS undercollection “loan” element previously reflected in bundled customer rates was removed.

Effective with its anticipated September 1, 2006 advice letter filing, however, PG&E agrees to adjust bundled customer power charges to reflect the overpayment by noncore bundled customers in the amount of \$325 million. This overpayment amount will be recovered from core bundled service customers and credited against the rates of noncore bundled customers over a 30-month period ending December 31, 2008. The equivalent annual increase to core bundled customers will be \$130 million with a corresponding annual decrease to noncore bundled customers.

**b. Discussion**

We find the proposed approach reasonable as a means of compensating noncore bundled customers for their excess contributions, and hereby adopt it. On September 1, 2006, January 1, 2007, January 1, 2008, and the January 1, 2009, the applicable adjustment shall be allocated among customer groups on an equal cents per kWh basis, by increasing or decreasing energy related generation surcharge components by an equal amount per kWh. In the residential class, consistent with current practice, the increase will be allocated proportionally to the Tier 3, Tier 4, and Tier 5 surcharges such that the revenue allocated to the residential class is fully collected from the residential class. On March 1, 2009, this differential adjustment to core and noncore bundled rates will be discontinued.

**2. For Edison's Customers**

**a. Parties' Position**

SCE's large bundled noncore customers have been paying an increment to fund the CRS undercollection since August/September 2003 per the SCE "settlement" charges (D.03-07-029). SCE estimates that its large bundled customers paid \$701 million toward funding the CRS undercollection by end of year 2005. The parties agree that this amount exceeds the high point of the CRS undercollection balance, and that large bundled customers have overpaid by \$95 million.

The parties agree that this "loan" increment should be removed from large bundled customer power charges through the filing of an advice letter which reduces large bundled customer power charges. Further, the parties agree that DA undercollection repayment amounts in 2006 and subsequent years should be credited to small and large bundled customers in the same proportion as such loan amounts were paid by small and large bundled customers.

**b. Discussion**

We find the proposal reasonable as a means of compensating noncore SCE bundled customers for their excess contributions. The \$95 million that the large bundled customers overpaid to fund the CRS undercollection “loan” relative to the maximum level of the DA CRS undercollection shall be reimbursed by small bundled customers following the date on which the CRS undercollection balance reaches zero, over a reasonable amortization period.

DA customers who received DA service during the period the DA CRS undercollection was incurred and who subsequently return to bundled service are responsible for repayment of a portion of that undercollection. The Undercollection Charge (UC) for these returning DA customers will be calculated on the same basis as applies for continuing DA customers, consistent with the provisions of D.03-05-034.<sup>22</sup> As noted in joint parties’ comments on the Draft Decision,<sup>23</sup> the resulting UC will be approximately 1.2¢ per kWh (*i.e.*, 2.7¢ less 1.0¢ for the HPC, less 0.5¢ for the DWR bond charge) applied toward the CRS undercollection reduction for SCE during 2006. The UC will be prorated based on the number of months that such customers received DA service while the DA CRS undercollection was being accumulated.

**3. For SDG&E Customers**

**a. Parties’ Position**

The DA CRS undercollection for SDG&E was paid off during 2005. SDG&E filed Advice Letter 1726-E-A to set the DA CRS power charge

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<sup>22</sup> See D.03-05-034, at p. 44.

<sup>23</sup> See July 10, 2006 Joint Comments of CLECA, CMTA, SCE and TURN on the Draft Decision, p. 4-5.

component to zero, effective November 15, 2005. Since the historical undercollection was paid off prior to the November 15 date, an overcollection amount exists that SDG&E proposes to credit from bundled to DA Non-Exempt customers through a separate advice letter filing.

**b. Discussion**

We find this approach reasonable and hereby authorize SDG&E to file an advice letter for this purpose as outlined above.

**F. Status of the 2.7¢ DA CRS CAP**

**1. Parties' Position**

In D.02-11-022, the Commission capped the CRS billed to DA customers at 2.7¢ per kWh. The total accrued DA cost obligation exceeded the revenues collected under the 2.7¢/kWh, however, resulting initially in a CRS undercollection. Based on forecasts examined in D.03-07-030, we concluded that the 2.7¢ DA CRS would eventually generate sufficient revenues to pay off the undercollections. As a precaution, we directed that the 2.7¢ cap be subject to biannual review and readjusted, if necessary, to assure the DA CRS undercollection would be paid off no later than the expiration of the DWR power contracts (*i.e.*, in 2011-2012).

A June 2, 2005 ALJ ruling, directed the Working Group to perform the necessary calculations to assess whether, or to what extent, the 2.7¢/kWh DA CRS cap should continue or be revised, consistent with the objectives of D.03-07-030. Accordingly, the Working Group updated forecasts of CRS obligations through 2011,<sup>24</sup> subject to alternative assumptions. The

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<sup>24</sup> D.03-07-030, Finding of Fact #3, stated, "a reasonable criterion for purposes of preserving bundled customer indifference with respect to DA load migration is to ensure full payback of the DA CRS undercollection no later than the end of the

*Footnote continued on next page*

Working Group analyzed whether the CRS undercollections from DA customers of each utility were forecast to be fully recovered by the time that DWR contracts expire based on assumptions concerning the 2.7¢/kWh CRS.

DWR, through its consultant, Navigant, Inc., prepared two alternative forecasts of CRS obligations through 2011. The first forecast (in Table 2A of the Report) applies the currently used benchmark and modeling approach. This benchmark is equal to the weighted average purchase and sale of short term power by each utility in a given year and limits the DWR power charge component of the CRS to a non-negative number. The second forecast (in Tables 2B and 2C of the Report) applies the revised benchmark proposed for the period 2006-11, and does not limit the DWR Power Charge component of the CRS to a non-negative number during that period.

DWR's consultant calculated the expected date that the paydown of the DA CRS undercollection is completed for each of the three IOUs. The paydown occurs by the time the DWR contracts expire using either the currently adopted methodology or the parties' proposed methodology.

Appendix Table 2A and Table 2C of the Working Group Report summarize the upper and lower estimates for the year that paydown of the CRS undercollection is completed based on data inputs and provided in Appendix C thereof. A comparison of these estimates under both the current and proposed CRS methodology is presented below:

**DA CRS UNDERCOLLECTION ESTIMATED PAYDOWN PERIODS**

| Utility | Current Methodology * | Recommended |
|---------|-----------------------|-------------|
|---------|-----------------------|-------------|

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DWR contract term expected to occur in 2011.” Although the last DWR contract does not actually expire until 2015, the vast majority of contracts expire by 2011.



|       |                        | Methodology**          |
|-------|------------------------|------------------------|
|       | Year Paydown Completed | Year Paydown Completed |
| PG&E  | 2008                   | 2006                   |
| SCE   | 2011                   | 2008                   |
| SDG&E | 2005                   | 2005                   |

\*Assumes Currently Adopted (Navigant) Methodology based on spot (*i.e.* less than 90 days) prices and sales as Market Price Benchmark.

\*\* Assumes Parties' Recommended Methodology based on use of one-year strips plus a RA/capacity value to set Market Price Benchmark.

Source: Navigant January 24, 2006 model results provided to CRS Working Group.

Based on these calculations, the parties agree that the DA CRS cap should remain at the current 2.7¢/kWh until the undercollection reaches zero for each IOU. Since the CRS undercollection for PG&E is expected to reach zero as of June 30, 2006, parties propose that the 2.7¢ cap be eliminated from the CRS calculation for PG&E after July 1, 2006. For SCE, DA CRS billings are expected to begin drawing down the undercollection in 2006, accelerating in late 2006 with the phase out of the HPC. At expected accrual and collection rates, SCE's combined undercollection balance of \$577 million is expected to reach zero before the end of 2008.

## 2. Discussion

We find parties' proposals concerning the phase out of the 2.7¢/kWh CRS cap to be reasonable, particularly since the CRS undercollections are expected to be paid off sooner than previously anticipated in D.03-07-030. We agree that the DA CRS cap of 2.7¢/kWh should remain in effect for SCE until the undercollection reaches zero, which is expected to occur in 2008. For PG&E,

we approve parties' recommendation that the 2.7¢/kWh CRS cap be removed as of September 1, 2006.<sup>25</sup>

The SDG&E undercollection of DA CRS obligations was fully paid off in 2005. SDG&E filed Advice Letter 1726-E, and Advice Letter 1726-E-A (replacing Advice Letter 1726-E in its entirety) proposing to suspend the DWR power charge component of the CRS as of November 15, 2005 to avoid large overcollections on an ongoing basis. The Energy Division has approved this advice letter, so that DWR will not receive any power charge revenues from DA customers in the SDG&E territory in 2006. SDG&E may file to reinstate the charge in the future, if necessary, depending on the effects of the adopted methodology and benchmark on future DA CRS charges. SDG&E shall file an advice letter, if necessary, to credit from bundled to DA Non-Exempt customers the overcollection amount resulting from the time lag of when the historical undercollection was paid off in 2005 and when the charge was set to zero on November 15, 2005.

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<sup>25</sup> In comments on the Draft Decision, parties proposed a revised date of September 1, 2006 to implement removal of the 2.7¢ kWh cap, rather than July 1, 2006. In reply comments on the Draft Decision, DWR expresses disagreement with the Working Group's intention not to adjust the DWR bundled Power Charge remittance to offset the decrease in remittances from DA load as a result of terminating the 2.7¢/kWh CRS cap. DWR claims that a reduction in the DA CRS remittance requires a corresponding increase in the bundled customers' remittance charge, and that failure to do so would be inconsistent with prior Commission decisions and with the DWR Rate Agreement. DWR proposes that PG&E be required to adjust its bundled Power Charge remittance amount to offset the decrease in DA CRS remittances as part of a compliance advice letter. We expect PG&E to make any appropriate adjustments in its applicable remittance charges for bundled and DA load as part of its advice letter filing to implement the PCIA tariff provisions adopted herein in accordance with the Rate Agreement.

## **G. Institution of the Power Charge Indifference Adjustment**

### **1. Parties' Positions**

Parties originally proposed effective July 1, 2006, to replace the DWR power charge component of the DA CRS, as currently identified on customers' bills, with a PCIA, as defined below. In comments on the Draft Decision, parties proposed a revised date of September 1, 2006 to implement removal of the 2.7¢/Kwh cap, rather than July 1, 2006. Parties propose that the CRS components be thereafter calculated on a bottoms-up basis rather than on the residual basis established in D.02-11-022. The DWR bond charge, the Energy Cost Recovery Amount (ECRA) rate, and the ongoing CTC will not change on September 1, 2006, nor will the basis for calculating the Franchise Fee Surcharge currently paid by DA customers.

The PCIA is intended to preserve the indifference concept adopted in D.02-11-022 for DA customers who pay the DWR power charge component of CRS. To accomplish this intent, the cost responsibility for ongoing CTC and the PCIA charge for DA customers who pay the DWR power charge would equal their responsibility under the indifference rate concept, plus recovery of franchise fees associated with the DWR revenues collected from direct access customers for the DWR bond charge and the DWR power charge.

### **2. Discussion**

We conclude that the proposal to institute the PCIA, as described below, is reasonable, and hereby adopt it. We shall adopt the proposed effective date of September 1, 2006 for the PCIA provisions to take effect for PG&E. For SCE, the PCIA shall be implemented consistent with the timing provisions set forth in D.06-06-067, regarding Phase 2 of SCE's 2006 GRC. Under this revised schedule, DA customers responsible for the DWR power charge will have paid

the full 2.7¢ per kWh CRS amount for two months more (July and August) than was anticipated by the DA Working Group Parties, two months longer than necessary to complete repayment of the DA CRS undercollection for PG&E.

Since the additional revenues from these customers paid during July and August, 2006, relative to what they would have paid had the agreement been put in place on July 1, 2006, will not be returned to them through any existing balancing account mechanism, the DA Working Group Parties propose bill adjustments for these customers. The adjustments would be calculated for July and August 2006, the difference between the CRS as it exists once it is lowered pursuant to the instant Commission decision and the CRS these non-exempt DA customers paid during July and August. To reflect the fact that the non-exempt DA customers will have fully repaid the DA CRS undercollection applicable to PG&E, by June 30, 2006, but that the DA CRS rates will not be adjusted until September 1, 2006, the DA Working Group that interest be provided for, at the same 90-day commercial paper rate generally applied to PG&E's balancing accounts, and that PG&E should provide these credits in a timely manner, recognizing that providing such adjustments is not a "business as usual" activity.

We find this proposal reasonable and hereby adopt it. For ratemaking purposes, these adjustments shall be treated as follows. The amount attributable to DA payments of DWR power charges that would not have been made in July and August 2006 be reflected as a debit to the Power Charge Collection Balancing Account (PCCBA), which establishes PG&E's bundled customers' responsibility for DWR power costs. The amount attributable to the negative PCIA for July and August is to be treated as negative PCIA amounts generally, as a debit to the ERRA.

The following provisions shall apply to the PCIA:

- The revenue requirement for the PCIA charge is the difference, positive or negative, between direct access non-exempt customers' share of the indifference amount and their share of the ongoing CTC revenue requirement, plus the franchise fees associated with the revenues collected from direct access customers for the DWR bond and power charges.
- The revenues collected from direct access non-exempt customers under the PCIA charge and the ongoing CTC, combined, are equal to these customers' share of the indifference amount, plus the franchise fees associated with the DWR revenues collected.
- The direct access non-exempt customers' responsibility for franchise fees associated with DWR revenues will be determined based on an estimate of DWR bond charge and power charge revenues paid by these customers, multiplied by the adopted franchise fee factor. No provision for franchise fees associated with DWR revenues will be assessed on direct access customers who pay the DWR bond charge, but not the DWR power charge.
- If direct access non-exempt customers' share of the indifference amount exceeds these customers' share of the ongoing CTC revenue requirement, then the difference is these customers' DWR power charge obligation. If the PCIA charge is positive, it has the effect of decreasing bundled customers' DWR remittance rate, and, for PG&E only, of decreasing bundled customers' Power Charge Collection Balancing Account rate.
- If direct access non-exempt customers' share of the indifference amount is less than their share of the ongoing CTC revenue requirement, then these customers' DWR power charge obligation is zero. If

the PCIA charge is negative, it has the effect of increasing bundled customers' ERRRA costs (for PG&E) or URG rates (for SCE). The PCIA charge (including franchise fees associated with DWR revenues collected by PG&E) will be set in proportion to the ongoing CTC.

The sum of the PCIA component and the ongoing CTC component equal the CRS indifference charge, calculated using the same market benchmark as used for ongoing CTC. SDG&E's ongoing CTC calculation in its 2006 ERRRA filing shall not be subject to the market benchmark from the DA CRS Working Group.

Based on parties' benchmark calculations, the average resulting PCIA charge for 2006 for PG&E is negative 0.306¢ per kWh and for SCE is negative 1.805¢ per kWh.<sup>26</sup> We adopt these figures for 2006 as being reasonable.

#### **H. Process for Future Updates of CRS Components**

Under current procedure, the DWR power charge component of CRS obligations is determined in this proceeding (R.02-01-011) while overall DWR revenue requirements and allocations are determined in a separate proceeding (currently in A.00-11-038 *et. al.*). By August of each year (or more frequently, if necessary), DWR generally notifies the Commission of its revenue requirement for the upcoming year. The Commission generally issues a proposed decision by November of the same year, which includes an inter-utility allocation of DWR costs and true-up of DWR costs for the year prior. For instance, in August 2006, DWR will notify the Commission of its 2007 revenue

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<sup>26</sup> This negative 1.805¢ figure is subject to adjustment should the Commission adopt the ALJ's recommendation with respect to treatment of administrative costs in Edison's 2006 GRC.

requirement and provide data for the Commission to calculate any inter-utility true-up for 2005.

Parties propose that for future determinations of the DA/DL CRS, each IOU file an advice letter at the end of each year or file an update to its ERRA to establish the indifference charge for the subsequent year, as well as the PCIA and ongoing CTC components of the DA CRS. This filing would be based on information contained in the DWR Revenue Requirement proceeding (presently A.00-11-038 *et al.*) and the utilities' ERRA proceedings, and subject to the data requirements in Section IV of the Report.<sup>27</sup>

We find this procedural approach reasonable and hereby adopt it. Thus, with the adoption of these procedures for determination of CRS requirements in the ERRA proceeding, there is no need to keep this proceeding open for subsequent determinations of CRS for DA or DL customers. With disposition of remaining issues concerning MDL CRS methodologies as discussed further below, we shall close R.02-01-011.

### **III. Issues Relating to MDL CRS Obligations**

In this decision, we also resolve issues relating to the CRS obligations of MDL customers.<sup>28</sup> By ALJ ruling dated March 28, 2005, the Working Group process was expanded to include MDL CRS issues, including the quantification of the level of MDL CRS obligations.

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<sup>27</sup> These data requirements are adopted as set forth in Appendix 2 of this order.

<sup>28</sup> Outstanding issues associated with the billing and collection of the CRS from departing load customers are being addressed separately in advice letters that PG&E and SCE have submitted to establish MDL billing and collection procedures. SDG&E elected not to file an advice letter for this purpose.

A number of Commission decisions establish the requirements regarding MDL CRS obligations and authorize limited exemptions from certain components of the MDL CRS.<sup>29</sup> The cost allocation for MDL CRS calculations depend on data inputs categorized by year. MDL customers are responsible for different amounts of CRS obligations based upon their year of departure from bundled service.

We resolve certain methodological issues concerning CRS obligations applicable to MDL customers in this order, as discussed below.

**A. MDL CRS Accruals and Undercollections  
as of December 31, 2005**

Table Appendix C-1, as reproduced in the Appendix of this decision sets forth the illustrative calculations of MDL CRS accrual rates for the period 2004-2011, based on the benchmark adopted in D.05-01-040 (applied through 2005) and the Working Group's recommended benchmarks through 2011. Accordingly, based on the calculations of the Working Group Report, we affirm that no DWR Power Charge undercollections apply to MDL customers as of December 31, 2005.

**B. Use of Market Benchmark  
for MDL CRS**

**1. Parties' Positions**

For determining MDL CRS obligations, the parties propose to apply the same market benchmark as described above to calculate the DA CRS (comprised of the cost of a one-year strip of power plus a RA/capacity adder). In this respect, the MDL Parties propose use of the procedures set forth in

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<sup>29</sup> See D.03-07-028, D.03-08-076, D.04-11-014, D.04-12-059, D.05-007-038, and D.05-08-035.



Section II of Appendix E of the Report as applying to the DL CRS for customers which pay the DL power charge.

The parties agree to calculate the DWR power charge component of the DL CRS to accommodate ongoing CTC and the indifference charge for customers who pay the DL power charge. Parties disagree, however, as to the point in time when the revised benchmark methodology should take effect. Some parties propose to apply the revisions starting in 2003. Other parties propose that the revisions only take effect prospectively in 2007.

## **2. Discussion**

We find the proposal reasonable to apply a consistent market benchmark to MDL as to DA and hereby adopt it. A consistent benchmark will provide for a more uniform and coherent approach to avoiding cost shifting and promoting bundled customer indifference. We shall also adopt a consistent starting point for both MDL and DL load, and authorize it to apply effective beginning with the 2006 calendar period. As stated previously, however the IOUs' previously adopted CTC for 2006 is not intended to be modified.

### **C. Applicability of Total Portfolio Indifference Standard to MDL**

#### **1. Parties' Positions**

Parties representing MDL interests agree with the consensus recommendation for determining how to set CRS for those non-bundled customers, including MDL customers, who are responsible for the costs of DWR power. Under the consensus proposal, DA and MDL customers that are not exempt from the DWR power charge would pay the sum of the ongoing CTC and the PCIA. This approach would not modify their ongoing CTC obligation.

Parties did not reach consensus, however, on how to determine the CRS obligation applicable to MDL customers who are exempt from the DWR power charge. The IOUs recommend applying the same approach to such MDL customers as for bundled and DA customers. For continuous DA customers and MDL customers who are exempt from paying the DWR power charge, the Working Group recommends that they simply pay ongoing CTC with no “total portfolio indifference” adjustment.<sup>30</sup>

The IOUs believe that the indifference principle is applicable only to those non-bundled customers responsible for paying the DWR power charge. Thus, the IOUs believe that a total portfolio indifference approach is applicable only to customers responsible for DWR power costs. If it were applicable to all DL customers, the IOUs argue, it would in effect mean that the ongoing CTC for all customers is calculated on a total portfolio basis. The IOUs believe that such an interpretation would be in contradiction to methodology for calculating ongoing CTC method adopted in prior Commission decisions.

Parties representing MDL interests recommend that a “total portfolio adjustment” apply to MDL customers who are *not* responsible for DWR power charges, but who pay ongoing CTC.<sup>31</sup> The “total portfolio adjustment” would allocate both the above or below market cost to MDL customers calculated in reference to the market price benchmark established in this proceeding.

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<sup>30</sup> In their filings, Parties refer to “statutory” CTC. However, as previously discussed, this phrase is synonymous with ongoing CTC, as there is only one methodology for calculating ongoing CTC (*i.e.*, pursuant to Pub. Util. Code § 367(a)(1) – (6)).

<sup>31</sup> See computational example in Appendix 1C of the Working Group Report.

For 2004-2006, an illustrative example is presented in Table Appendix C-1, of the DL recommended methodology and benchmark.<sup>32</sup> For 2007 forward, the total portfolio adjustment would be determined in the ERRRA proceeding and applied to non-bundled customers exempt from the DWR power charge and subject to ongoing CTC. Projected results based on various alternative benchmarks and methodologies are shown on an illustrative basis in the same table.

MDL parties argue that the “total portfolio adjustment” is necessary to ensure equivalent treatment of DA and DL customers, and to keep bundled customers indifferent to the departure of all DA and DL customers. Specifically, they argue that migrating customers subject only to ongoing CTC will not receive the benefit of the below market costs of the residual portfolio. MDL parties believe that the resulting charges would be inconsistent with the total portfolio approach for determining bundled customer indifference, and that bundled customers would not be indifferent to the departure of the load, but would be benefit from it.

The IOUs argue that MDL parties’ position is illogical and inconsistent with the Commission’s determination that ongoing CTC would be calculated based on the requirements of Pub. Util. Code § 367(a)(1) – (6). The IOUs characterize any use of the indifference charge to modify “statutory” CTC for these customers as nothing more than a “back door” way of determining a “total portfolio” CTC charge for them.

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<sup>32</sup> The total portfolio adjustment would not apply for year 2003 as, in accordance with D.05-01-040, issued in this rulemaking proceeding in January 2005, the CTC rate for 2003 has been set at \$0.00.

Under current market conditions, the obligation to pay DWR power costs actually serves to lessen these customers' total CRS obligations, as the total portfolio indifference charge is currently lower than the ongoing CTC. However, under past market conditions responsibility for the DWR power costs has placed burdens, rather than benefit, on these customers. If market conditions change in the future, lowering market rates, then the DWR obligation may again increase these customers' burdens.

The approach described in the Working Group Report is intended to apply regardless of market conditions, or whether the DWR cost responsibility works to reduce, or increase, non-bundled customers' total obligations. From the IOUs' perspective, the appropriate distinction to determine whether a non-bundled customer pays the ongoing CTC only, or the ongoing CTC plus the PCIA, is whether the non-bundled customer is responsible for the costs of DWR power. The IOUs argue that if the non-bundled customer is exempt from DWR power costs, then the customer should incur the "statutory" CTC, according to D.05-12-045. The IOUs argue that there should be no "indifference" or "total portfolio" adjustment for such customers. Otherwise, the IOUs argue, the customer would not pay "statutory" CTC, but would pay a "total portfolio"-based CTC in contravention of D.05-12-045.

## **2. Discussion**

Consistent with D.05-12-045, we affirm that the method for calculating ongoing CTC for all customers, regardless of whether they pay a DWR power charge, is based on Pub. Util. Code § 367(a)(1) – (6). As explained in D.05-12-045, parties in that proceeding were mistaken in believing that there is a "total portfolio" method to calculate ongoing CTC for at least some customer groups. As a result, in D.05-12-045, we found that most of parties' arguments in

that proceeding as to whether a “total portfolio” method should be used to calculate ongoing CTC were inapposite.

In D.05-12-045, moreover, we reached no final disposition as to the applicability of the total portfolio indifference method to MDL customers that are exempt from the DWR power charge. We stated therein that questions “regarding the use of the total portfolio method to determine the indifference costs included in the CRS” were deferred for resolution in R.02-01-011.<sup>33</sup> Accordingly, D.05-12-045 does not prejudge nor preclude the applicability of a total portfolio indifference standard for MDL customers in the instant order.

In this decision, we therefore determine the applicability of the total portfolio adjustment in deriving MDL customers’ cost responsibility obligations. We conclude that the total portfolio adjustment properly applies to MDL customers *only* if they pay a DWR power charge, but does *not* apply to MDL customers that pay *no* DWR power charge. The total portfolio adjustment was instituted to ensure that bundled customers remain indifferent to the impacts of DA and DL customer migrations associated with DWR power contracts. We have not, however, previously applied a total portfolio adjustment to DA or customer generation DL customers that pay *no* DWR power charge. This guiding principle as to the limited applicability of the total portfolio methodology is summarized in D.05-01-035 at page 2<sup>34</sup> which states:

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<sup>33</sup> D.05-12-045 at 20.

<sup>34</sup> See D.05-01-035, Order Modifying Resolution 3831, and Denying Modification of Resolution as Modified. Resolution E-3831 implemented the cost responsibility surcharge for customer generation departing load, as mandated by D.03-04-030, as modified by D.03-04-041.

We note that the applicability of the total portfolio methodology depends on whether the customer is paying the power charge. Regardless of whether they are bundled, direct access or departing load customers, when a customer pays the power charge, the total portfolio calculation applies. When a customer does not pay the power charge, *e.g.*, continuous DA customers and certain excepted [customer generation departing load] CGDL customers, the calculation does not apply. However, in either case, the calculation of the tail CTC is based on the Public Utilities Code Section 367(a)(1)-(6) requirements.

Consistent with this limitation, customers that pay no DWR Power Charge still remain responsible for paying at least the costs associated with CTC as prescribed in Pub. Util. Code § 367 (a). The discussion in D.05-01-035 explicitly referenced only DA customers and customer generation DL customers. MDL parties have provided no justification, however, to treat MDL customers any differently in a manner inconsistent with D.05-01-035.

As prescribed in D.05-12-045, only the statutory method should be used to calculate ongoing CTC on a consistent basis across all customer categories. The MDL parties argue that the total portfolio indifference adjustment does not reduce CTC, but merely accounts for the additional costs of the IOU portfolio that are not included in the CTC calculation. As such, the MDL parties contend that applying the total portfolio calculation to MDL customers exempt from the DWR Power Charge is consistent with uniform application of the CTC.

We disagree with the MDL parties characterization in this regard. Such characterization does not change the practical result that the total portfolio calculation reduces the payments due from MDL customers below the statutory

CTC level. Such an outcome is contrary to the requirement for uniform CTC treatment to apply across customer categories.

We conclude, therefore, that MDL customers should be treated consistently with DA and customer generation DL with respect to CTC obligations. Accordingly, the total portfolio indifference calculation shall apply to MDL customers only if they pay a DWR power charge. For MDL customers that do not pay a DWR power charge, the total portfolio indifference calculation shall *not* apply. MDL customers remain responsible, at a minimum, for payment of CTC as required under Sec.367 irrespective of whether a DWR power charge applies. MDL customers must bear a fair share of cost responsibility consistent with our treatment of DA and Customer Generation DL as referenced in D.05-01-035 above.

Our treatment here is also consistent with D.03-07-028 which indicated that to avoid cost shifting, MDL customers bear responsibility for a fair share of costs necessary to achieve bundled customer indifference.<sup>35</sup> To apply this indifference standard properly, however, MDL customers must be treated in a manner consistent with that of DA and customer generation DL customers regarding the total portfolio indifference calculation. The treatment we adopt here achieves this consistency.

We thus conclude that applying a bundled customer indifference standard is not appropriate in deriving the cost responsibility for MDL customers if no DWR power charge is paid. We shall apply a total portfolio indifference standard to MDL CRS obligations only where a DWR power charge

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<sup>35</sup> See D.03-07-028 at 13.

is applicable. The indifference adjustment does not change the ongoing CTC that applies uniformly to all bundled, DA and DL customers.

**D. Applicability of Credits for Individual Customers that Migrate From Bundled to MDL**

**1. Parties' Position**

MDL parties propose that individual bundled customers who become municipal departing load customers prior to the full repayment of the CRS undercollection receive credits against their CRS obligation. The DL parties propose to adjust individual bundled customers' bills retrospectively so that each customer would receive a portion of the not-yet-repaid DA CRS loan, if the customer departed from bundled service prior to full repayment of the CRS loan.

Under this proposal, determination of any credit due to a transferred MDL customer would be a function of the amount of the CRS undercollection at the time the customer departed.<sup>36</sup> The DL parties propose a one-time determination of this credit based on the "vintage" of the MDL. MDL customers that were DA customers during the period when the liability accrued would not be eligible for the credit.

The IOUs oppose this proposal, characterizing it as administratively complex and ill-advised. The IOUs also argue that the proposal does not account

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<sup>36</sup> For example, Turlock Irrigation District (TID), pursuant to a negotiated agreement with PG&E, assumed a specified number of transferred MDL customers on December 8, 2003. Pursuant to a previous Commission decision, prior to the transfer, those customers paid PG&E bundled service rates. While a rate freeze was in effect at the time the customers were transferred from PG&E to TID, in March 2003, the Commission had approved a three cent rate increase paid by all bundled service customers. Accordingly, DL parties argue that from March 2003 until December 2003, current TID customers helped subsidize the CRS undercollection and should be reimbursed for such contributions.



for the possibility that other balancing accounts may be undercollected at the time the customers depart, nor hold such customers responsible retrospectively for such undercollections.

The IOUs characterize the proposal as a request that MDL customers be paid to depart from the IOU's system. As a general policy, the IOUs argue that the Commission should not require bundled customers to make such payments to departing load customers. The IOUs argue that a better approach here is the simpler one, and that the Commission should ensure that bundled customers collectively receive full repayment of the DA CRS loan.

## **2. Discussion**

We decline to authorize a credit to individual groups of customers who depart to MDL status. With respect to the DA CRS undercollections, bundled customers as a group are entitled to repayment of the "CRS loan" they provided to DA customers. The entitlement of bundled customers, on a group basis, however, does not entitle specific bundled customers to individual "refund amounts." That would be, in effect, a retrospective adjustment to the cost responsibility for electricity received earlier. Instead, the loan is repaid as an adjustment to bundled customers' charges on a prospective basis.

If a bundled customer leaves the IOU's service territory before complete repayment of the loan, that customer does not receive a check from the utility. Likewise, a balancing account may be overcollected in a given year, indicating that customers paid a surplus for that year. However, such overcollection does not entitle any individual customer to a refund. Instead, future charges are reduced to amortize the overcollection. Ratepayers, in general, receive the benefit of the lower charge, but no refund checks are provided based on any customer's past consumption.

Individual, retrospective refunds as proposed would also be administratively burdensome to administer. With such after-the-fact adjustments, customers never have certainty at the time they are consuming utility service as to their cost responsibility for that service. For these reasons, we decline to authorize retrospective adjustments to individual customers who depart from bundled service to MDL status.

## **E. Treatment of Negative CRS for MDL Customers**

### **1. Parties Positions**

The MDL and IOU parties disagree concerning how to treat negative components of the CRS, including whether a particular negative CRS component may be used to offset any other CRS components (other than ongoing CTC). As indicated above, a negative CRS component may result where the ongoing CTC amount is larger than the overall CRS indifference charge.

The DL participants believe negative CRS components should be used to offset other CRS components in order to maintain bundled customer indifference. The DL participants believe that the CRS components represent various costs of power commitments made by or on behalf of the IOUs prior to the time of the DL customer's departure. DL Parties believe that in order to ensure that bundled customers' charges do not change from the departure (*i.e.*, are no longer indifferent), the offsets of the various cost components should be allowed to occur.

To the extent that the DWR power charge is a negative amount and offsets ongoing CTC in its entirety, the DL participants believe that the indifference charge should be allowed to go negative. Once the negative indifference charge has been applied to recover past undercollections, they propose that it offset other CRS components. In any month in which a negative

indifference charge is not used to offset past undercollections or other CRS components, they propose that it be carried forward to offset future CRS. DL parties believe this is consistent with the treatment of ongoing CTC in D.05-12-045.

The IOUs believe that the indifference charge should remain non-negative for each IOU after that IOU's existing CRS undercollection is eliminated. The IOUs argue that allowing the indifference charge to become negative after the existing CRS undercollection is eliminated is effectively paying DL customers for departing from the IOUs' procurement activities. Additionally, use of a negative indifference charge to offset other CRS charges such as the DWR bond charge or PG&E's ECRA charge is inappropriate. This argument, were it successful, would also impact the very nature of the consensus benchmark agreement which represented a compromise between the DA Agreement Parties. The IOUs indicate that they would be far less comfortable with the agreed benchmark if it could lead to payments to certain groups of DL customers.

## **2. Discussion**

In D.05-12-045, we directed that beginning in 2006 and subsequent years, negative ongoing CTC shall be netted against positive above-market costs included in ongoing CTC (referred to as positive ongoing CTC). The use of negative ongoing CTC to offset positive ongoing CTC yields a more accurate measurement of total above-market costs over time.

We directed in D.05-12-045 that any negative ongoing CTC that occurs in 2006 and subsequent years may only be used to offset positive ongoing CTC during these years, with no accrued interest. We directed that the tracking of negative ongoing CTC would cease when all ongoing CTC costs had been

recovered, and that any remaining negative ongoing CTC balance would have no further effect on cost allocation or rates.

In D.05-12-045, we restricted the use of negative ongoing CTC only to offset positive above-market costs, but not to offset other components of ongoing CTC (*e.g.*, QF restructuring costs) or other CRS components. This is because negative ongoing CTC provides no cash, and thus, cannot be used to offset costs that involve actual cash expenditures (*e.g.*, QF restructuring costs). We indicated, however, that D.05-12-045 did not prejudge how to treat any negative amounts that may result when the total portfolio method is used to calculate the indifference costs recovered via the CRS.

D.05-12-045 did not result in the payment of negative ongoing CTC to any customers, but merely expanded the period of time for measuring ongoing CTC, so that negative ongoing CTC in future years is used to offset positive ongoing CTC in future years. Based on these considerations, we adopt the IOUs' proposals, as outlined above, concerning limitations on the treatment of negative ongoing CTC. The indifference charge shall remain non-negative for each IOU after that IOU's existing CRS undercollection reaches zero. A negative ongoing CTC-plus-PCIA amount shall not offset other components of the CRS. Any reduction provided to MDL customers, whether it is a direct refund or a reduction in another CRS component, must be funded by the remaining bundled customers. Therefore, no offset to other CRS components shall be allowed. MDL customers should not be paid for departing from the IOUs' procurement activities. Any accumulated negative indifference amounts shall continue to be tracked, however, and applied to any future positive indifference amounts that may accrue.

## **F. Allocation of CRS Exemptions Among MDL Customers**

### **1. Parties' Position**

The parties reached consensus on procedures for allocating the DWR power charge exemptions for transferred MDL. In D.03-07-028, the Commission adopted provisions for publicly owned utilities (POUs) to qualify for MDL CRS exclusions for new load on behalf of qualifying customers. The administration of such exclusions, however, was left to the MDL billing and collection implementation phase. D.04-12-059 [which addressed applications for rehearing of D.04-11-014, the decision on rehearing of D.03-07-028] adopted MDL CRS exclusions for new load associated with (1) POU serving in geographic areas identified in the PG&E Bypass Report for transferred load and (2) POU formed before July 2003 capped on an interim basis at 80 MW.

In D.04-11-014, the Commission provided a list of publicly-owned utilities who had already met the eligibility criteria to apply for any available CRS exception on behalf of the qualifying MDL. In addition, in D.06-03-004, the Commission established protocols for POU not identified in PG&E's Bypass Report to claim eligibility for DWR power charge exemptions. The Commission has further clarified that new load located in the geographic area "identified in the PG&E Bypass Report attributable to transferred MDL, as the existing POU existed at the time of the Bypass Report" receive an unlimited exemption from the DWR Power Charge. (D.05-07-038, Finding of Fact 10.) Therefore, there is no need to allocate or otherwise track such new load exemptions for MDL.

An ALJ ruling dated December 23, 2004, solicited proposals concerning, among other items, protocols for administering the first-come, first-served rules for POU seeking to qualify for authorized CRS exclusions on behalf of their customers. A workshop held on January 31, 2005 reached a

productive outcome on this question for MDL “transferred load.”

Working Group representatives presented a joint proposal for “Allocation of Transferred Load Exceptions from the CRS.” On October 3, 2005, members of the Working Group met to discuss and develop recommended protocols, and used the January 31, 2005 POU proposal as their starting point for specific protocols that can be implemented by the Commission. The Working Group recommends that, as applicable, these principals be applied to protocols for the “first-come, first-served” exceptions provided to transfer departing load. Separate protocols will be necessary for new load.

At the meeting, PG&E agreed to compile its confidential load data for each affected POU and to provide that data to the Energy Division for distribution.

## **2. Discussion**

We find the proposed procedures for allocation of transferred MDL to be reasonable and hereby adopt them, as summarized below. The following principles shall apply in administering the MWh exceptions from the CRS allocated to transferred MDL, as adopted in D.04-11-014, as modified by D.04-12-059.<sup>37</sup>

- CRS will assessed as a volumetric based on historical pre-departure metered consumption:
  - Historical pre-departure metered data will be determined as recorded in each customer’s departing load statement.

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<sup>37</sup> D.04-12-059 was clarified in D.05-07-038, which was issued after the January 2005 workshop.

- IOUs will cooperate in providing copies of each customer's departing load statement to the serving POU.
- POU's determination of the amount of load eligible for an annual exception shall be done on an annual basis.
- POU's will provide the amount of their transferred load exception for the previous year to DWR by February 1 of the following year:
  - Priority allocation for transferred load CRS exceptions shall be (1) entities named in the Bypass Report up to the full amount set forth in the report, followed by; (2) POU's with customers departing PG&E bundled service on a first-come, first-served basis, followed by; (3) all other eligible POU's on a first-come, first-served basis.
  - Each year, entities named in the Bypass Report have priority for up to the full amount set forth in the Report; however, once established, the priority for allocating excess exceptions will be followed each year.
- Any exception amount not used in a calendar year remains available for [use by qualifying DL in] subsequent years.
- POU's are not required to provide any customer specific information to the IOUs.
- Each year, the CRS transferred load exceptions are assigned to the load of a POU, and not to particular customers.
- Payment of CRS will be for the preceding year.
- For entities not named in the Bypass Report, first-come, first-served priority for the CRS exception should be determined on the date the affected service area came under the control of the POU (by annexation, agreement or otherwise).

- Any collection costs incurred by the IOU are the responsibility of the IOU.

#### **G. Conversion of MW Cap Into MWh Figure**

In D.04-11-014, the Commission granted a CRS exception cap up to 150 MW of “new” MDL in the PG&E and SCE territories, available through 2012. The Commission set this cap on an interim basis, and allowed parties “to revisit the size of the cap (but not whether there should be a cap), through workshops or other means as determined by the assigned ALJ, in the billing and collections phase of this proceeding.” (D.04-11-014 at 14.)

Decision 04-12-059 (on rehearing of D.04-11-014) reduced the interim cap from 150 MW to 80 MW and reiterated that “the amount of the cap is interim in nature and shall be revisited in the billing and collections phase of this proceeding.” (D.04-11-014 at 14.) The Commission further stated: “We expect that during this phase, the parties will present for our consideration a specific amount for the cap, whether 80 MW or another number, that is fully presented, explained and justified.” (D.04-12-059 at 24.)

Parties remain in disagreement as to a specific amount for the cap, whether 80 MW or another number. For the present time, therefore, the 80 MW cap remains in effect. In rulings on December 23, 2004 and January 26, 2005, the IOUs to were directed to “provide system average load factors ... from which the applicable MW caps can be converted into a corresponding MWh figure.” PG&E and SCE provided preliminary load factor figures at the January 31, 2005 workshop and confirmed those figures in follow-up communications with the Energy Division.

The December 23, 2004 ALJ Ruling also solicited comments on the appropriate methodology for converting the 80 MW cap into a MWh figure. In



its January 14, 2005 opening comments, PG&E proposed that the 80 MW cap be multiplied by 8,760 hours per year, which should then be multiplied by a system average load factor. No party expressed any objection to this approach. In its April 15, 2005 comments, DWR indicated it did not wish to administer the program. As a result, the Energy Division recommends that it take on this responsibility itself. Accordingly, we shall delegate responsibility for administering this program to the Energy Division, and adopt PG&E's proposal as to the conversion of the 80 MW cap into a MWH figure.

## **H. Protocols for Allocation of Exemptions for New MDL**

### **1. Parties' Positions**

New load of POUs not named in PG&E's Bypass Report but "serving at least 100 customers as of July 10, 2003" are exempt from the DWR Power Charge up to a cap of 80 MW.<sup>38</sup> The Working Group discussed, but did not agree upon protocols for administering such new MDL exemptions. The IOUs argue that the criteria for qualifying for the 80 MW new load exemption are identical to the criteria for qualifying for the "leftover" transferred load exemption, and that the same procedures adopted in D.06-03-004 can apply for determining which POUs qualify for the new load exemption.

The IOUs propose that 15 days following a Commission decision adopting the new load protocols, the Energy Division would post that 80 MW of new load exemption is available. Within 10 business days, POUs that qualify for the new load exemption would notify the Energy Division of their interest in the available exemptions, with an estimate of their exempted new load (similar to

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<sup>38</sup> D.04-11-014, Ordering Paragraph 2; D.04-12-059, Ordering Paragraph 1.a.

step 2). The IOUs propose that they be given 5 business days to confirm or comment on, as the case might be, the POU's notification to the Energy Division. Within 30 business days after that, the Energy Division would notify the POU whether their request for exemption was granted. The Energy Division would regularly update the amount of new load exemption available, as requests for exemption are processed on a first-come, first-served basis.

The MDL parties, however, argue that there is insufficient information in the Working Group Report upon which to determine the appropriate procedures for allocation of such new load.

## **2. Discussion**

The Working Group Report indicates that the amount of actual transferred departed load and new departed load in the IOU service territories is currently well below the total exemptions available. However, protocols are needed to allocate exemptions for transferred load when and if such exemption limits are reached. We direct the Energy Division to reconvene the Working Group within 30 days of this decision for the purpose of reaching a consensus on protocols for allocating exemptions for new load.

## **IV. Comments on Draft Decision**

The draft decision of the ALJ in this matter was mailed to the parties in accordance with Pub. Util. Code § 311(g)(1) and Rule 77.7 of the Rules of Practice and Procedure. Comments were filed on July 10, 2006 and reply comments were filed on July 17, 2006. We have taken the comments into account, and made various revisions as warranted, in finalizing this order. Among other things, we have revised the Draft Decision regarding the applicability of the total portfolio adjustment for MDL CRS obligations to be consistent with the treatment accorded DA customers that are exempt from the DWR power charge. We have

also adjusted the implementation dates for tariff revisions resulting from this order, as proposed in parties' comments.

## **V. Assignment of Proceeding**

Geoffrey F. Brown is the Assigned Commissioner and Thomas Pulsifer is the assigned Administrative Law Judge in this proceeding.

## **Findings of Fact**

1. D.02-03-055 determined that as a condition of retaining the DA suspension date of September 21, 2001, bundled customer indifference should be preserved and no cost shifting from DA to bundled customer load should be allowed.

2. The Working Group formed pursuant to this proceeding did not reach consensus as to a single methodology to calculate the CRS undercollections as of December 31, 2005, but did reach a compromise consensus on the year-end 2005 CRS undercollection balance for each of the IOUs.

3. The consensus falls within a range of undercollection values calculated by the Working Group based both upon the existing market benchmark and a revised market benchmark using the MPR model as developed in R.04-04-026 and used in the ongoing CTC calculation in PG&E's 2006 ERRRA proceeding. The resulting illustrative CRS accrual rates calculated for the 2003-2011 period based on the benchmark adopted in D.05-01-040 compared with Working Group recommendations are set forth herein in Appendix 5, Tables 1A-1C.

4. As support for its consensus on undercollection balances as of December 31, 2005, the Working Group presented calculations of undercollections for 2003-2011 under alternative benchmark assumptions as set forth in Appendix 5, Tables 2A and 2B.

5. As part of the Working Group process, parties reached consensus on a DA CRS undercollection for PG&E in the amount of \$30 million as of

December 31, 2005, and also reached consensus that PG&E's undercollection is \$30 million for DWR bond charge recovery, applicable to DA load as of December 31, 2005.

6. Parties reached consensus on a DA CRS undercollection of \$522 million for SCE as of year-end 2005. Parties also agreed on an undercollection of \$55 million for SCE applicable to the DWR Bond Charge.

7. Parties agree that the DA CRS undercollection had already reached zero for SDG&E by December 31, 2005.

8. SDG&E filed Advice Letter 1726-E-A to set the DA CRS power charge component to zero, effective November 15, 2005.

9. Since its historical undercollection was paid off prior to the November 15, 2005, an overcollection exists that SDG&E will credit from bundled to DA Non-Exempt customers through a separate advice letter filing.

10. The Working Group identified several problems with the current CRS methodology in that it has proven cumbersome, administratively difficult and slow to provide predictions of the indifference charge. Parties are left without timely information concerning the level of CRS applicable to current consumption.

11. The Working Group participants agreed on the need for a revised simplified market benchmark methodology, on a prospective basis, based on futures prices. As a specific market proxy, parties agreed on an average of one-year strip power futures quotes for NP 15 and SP 15 as published in *Megawatt Daily*.

12. Working Group participants also recognized that because futures market prices may not adequately reflect all fixed RA/capacity costs, a cost adder should be incorporated into the benchmark for each IOU.

13. Although parties reached consensus on the level of the DA CRS undercollection for PG&E as of December 31, 2005, the parties were not able to agree on market price benchmarks for PG&E for 2004 or 2005.

14. Effective January 1, 2006, the implementation of the Phase 2 bundled rates in PG&E's 2003 GRC removed the undercollection loan element previously reflected in bundled customer rates.

15. For 2006, the market benchmarks developed by the Working Group result in the DA non-exempt customers' CRS obligations of \$90.12/MWh (\$95.52 at the meter) for PG&E and \$95.17/MWh (\$100.22 at the meter) for SCE. These benchmarks represent the 30-day average, over the period from November 15, 2005 to December 15, 2005, of 12 month forward prices for 2006 at NP 15 and SP15, respectively.

16. As the sales forecast for computing direct access non-exempt customers' 2006 CRS obligations, the Working Group agreed to use data from the IOUs' ERRRA proceedings, as modified by the 2006 Annual Electric True-Up for PG&E.

17. The Annual Electric True-Up is an advice letter process in which PG&E consolidates revenue requirements authorized by the Commission during the year for a rate change effective January 1<sup>st</sup> of the following year.

18. Since March 2004, for PG&E, noncore bundled customers have contributed excess revenues to fund the CRS undercollection loan in the amount of \$325 million, which payments benefited core bundled customers through lower power charges.

19. SCE's large bundled customers paid an estimated total of \$701 million toward funding the CRS undercollection "loan" by end of year 2005. This amount exceeds the high point of the CRS undercollection balance, and large bundled customers have overpaid by \$95 million.

20. SCE agrees to file an advice letter to reduce large bundled customer power charges, with DA undercollection repayment amounts to be credited to small and large bundled customers, respectively, in the same proportion as such loan amounts were paid.

21. The \$95 million that the large bundled customers of SCE overpaid to fund the CRS undercollection loan relative to the maximum level of the DA CRS undercollection should be reimbursed by small bundled customers following the date on which the CRS undercollection balance reaches zero, over a reasonable amortization period.

22. In D.03-07-030, the 2.7¢/kWh CRS cap was continued subject to periodic review, to be readjusted, if necessary, to assure the DA CRS undercollections would be paid off no later than the expiration of the DWR power contracts.

23. Based on updated forecasts of CRS accruals and collections performed and reviewed by the Working Group, parties agree that the 2.7¢/kWh cap no longer applies to SDG&E, can be discontinued for PG&E effective September 1, 2006, and should continue in place for SCE until the CRS undercollection is eliminated, currently estimated to occur by year-end 2008.

24. The Working Group agrees that the adopted market price benchmark should be applied consistently across all relevant CRS components, including both ongoing CTC and DWR charges.

25. A negative PCIA can result where ongoing CTC is larger than the total indifference charge.

26. Because non-exempt DA customers in SCE service territory are subject to a much larger CRS undercollection than DA customers in the other territories, the parties agree that any negative indifference charge that may occur for SCE may offset any existing DA CRS undercollection.

27. The parties' agreement is reasonable that once the existing CRS undercollection is eliminated, the indifference charge for non-exempt DA customers should *not be* permitted to decrease below zero. However, any accumulated negative indifference amount shall continue to be tracked and applied to any future positive indifference amounts that may accrue in later years of the applicability of the DA CRS.

28. The parties' proposal to replace the DWR power charge with a PCIA is a reasonable way to preserve the indifference concept.

29. In D.03-07-028, and related decisions, the Commission prescribed requirements for the CRS obligations applicable to MDL customers, and authorized various exclusions for certain CRS elements.

30. Based the findings of the Report, no reported undercollections are applicable to MDL CRS obligations as of December 31, 2005 for PG&E or SDG&E.

31. Table Appendix C-1, as reproduced in the Appendix of this decision, sets forth illustrative MDL CRS accrual rates for the period 2004-2011, based on the benchmark adopted in D.05-01-040 (applied through 2005) and the Working Group's recommended benchmarks through 2011.

32. The application of a total portfolio indifference standard to MDL customers who do not pay a DWR power charge is inconsistent with the intent of D.03-07-028 to avoid cost shifting and also conflicts with the affirmation in D.05-12-045 that ongoing CTC is calculated on a "statutory" basis.

33. Calculating a separate credit for individual customer groups who depart to MDL status would be administratively complex and inconsistent with the manner in which DA customers are treated.

34. The proposals in the Report concerning the administration of CRS exemptions for transferred load among MDL customers, as summarized in Appendix 4 of this decision, are reasonable.

35. The proposals in the Report concerning the administration and conversion of the 80 MW cap for MDL exemptions are reasonable.

### **Conclusions of Law**

1. The consensus recommendations reached by parties concerning the level of CRS undercollections for each of the IOUs as of December 31, 2005 reasonably balance the divergent views of affected interests and should be adopted.

2. The parties' consensus recommendations concerning the adoption of revised procedures for deriving the market benchmark proxy for purposes of computing CRS indifference on a prospective basis are reasonable and should be adopted.

3. The parties' proposal is reasonable for purposes of deriving a sales forecast for CRS indifference calculations to utilize data from the IOUs' ERRA proceedings, as modified by the 2006 Annual Electric True-Up for PG&E. Any modifications to the ERRA sales forecast that PG&E may make in its annual electric true-up advice letter, however, must have been previously authorized by a Commission order.

4. A negative indifference charge may be used to offset any existing positive CRS undercollection until such time as the CRS undercollection is eliminated for each IOU, but a negative indifference charge should not result in a net payment to customers that have left utility service.

5. PG&E should file an advice letter to adjust its bundled customer power charges to reflect the overpayment of \$325 million by noncore bundled customers to be amortized over a 30-month period.



6. SCE should file an advice letter to adjust its bundled customer power charges to reflect the overpayment of \$95 million by noncore bundled customers.

7. SDG&E should file an advice letter to adjust its bundled customer power charges to reflect the applicable overpayment by noncore bundled customers.

8. Based on the payoff dates for the CRS undercollections, the 2.7¢/kWh CRS should be terminated immediately for SDG&E. The CRS undercollection reached zero for PG&E on June 30, 2006, and the 2.7¢/kWh CRS should be terminated as of August 31, 2006 for PG&E. For SCE, the 2.7¢/kWh CRS should continue until the CRS undercollection is paid off, currently estimated to occur before the end of 2008.

9. Effective September 1, 2006, for PG&E and consistent with the timing set forth in D.06-06-067 for SCE, the DWR power charge should be replaced with a PCIA, according to the terms proposed by the Working Group, as set forth in Ordering Paragraph 15.

10. On a prospective basis, the PCIA should be updated by each IOU through its annual ERRRA filing process.

11. The Undercollection Charge (UC) for returning DA customers should be calculated on the same basis as applies for continuing DA customers, consistent with the provisions of D.03-05-034. The resulting UC is approximately 1.2¢ per kWh (*i.e.*, 2.7¢ less 1.0¢ for the HPC, less 0.5¢ for the DWR bond charge) applied toward the CRS undercollection reduction for SCE during 2006. The UC will be prorated based on the number of months that such customers received DA service while the DA CRS undercollection was being accumulated.

12. The same market benchmark adopted for calculating the DA CRS obligations should also be used on a consistent basis for calculating MDL CRS obligations.

13. The methodology for calculating CRS for MDL customers exempt from the DWR power charge should not incorporate a total portfolio indifference standard.

14. The application of a total portfolio indifference standard to the CRS obligation of MDL customers exempt from a DWR power charge conflicts with the requirement that a ongoing CTC applies on a uniform statutory basis to all customers.

15. MDL customers should not receive separate credits against the CRS obligations for departure to MDL status prior to the full repayment of the DA CRS undercollection.

16. The indifference charge should remain nonnegative after the CRS undercollection is eliminated, and negative rates should not be used to offset other CRS components once past CRS undercollections have been paid off.

17. The proposals in the Report concerning the administration of CRS exemptions for transferred load among MDL customers, as summarized in Appendix 4 of this decision should be adopted.

18. The proposals in the Report concerning the conversion of the 80 MW cap into a MWh figure for MDL exemptions should be adopted.

## **O R D E R**

### **IT IS ORDERED** that:

1. Direct Access Cost Responsibility Undercollections as of December 31, 2005 for each of the following investor-owned utilities (IOUs) are hereby adopted as follows. For Pacific Gas & Electric (PG&E), the cost responsibility surcharge (CRS) undercollection is \$30 million and the California Department of Water Resources (DWR) bond charge Undercollection is

\$30 million. For Southern California Edison (SCE), the CRS undercollection is \$522 million and the DWR bond charge undercollection is \$55 million. For San Diego Gas & Electric Company, the CRS undercollection is zero.

2. Effective for periods beginning on or after January 1, 2006, the CRS Indifference calculation shall be modified to incorporate the benchmark power determined as prescribed in Appendix 1. However, the utilities' already adopted ongoing CTC rates for 2006 are not intended to be modified as a result of this decision.

3. For 2006, the Resource Adequacy Generation Capacity (RA/capacity) cost adder will be \$8/megawatt-hours (MWh) for SCE and \$4/MWh for PG&E, which will be added to the average strip price.

4. The Energy Division is directed to coordinate a meeting of the Working Group within 30 calendar days from the effective date of this order to develop a record as to the level of the RA/capacity cost adders for years after 2006 as more information concerning the cost of generation capacity and/or resource adequacy becomes available.

5. For PG&E, the market benchmark for 2006 will be \$90.12/MWh. For SCE, the new market benchmark for 2006 will be \$95.17/MWh.

6. On an annual basis the revised benchmark power cost, as prescribed in Appendix 1, will be compared to the average cost of the utilities' total portfolio, including both utility retained generation (URG) power and allocated DWR power costs, to determine the level of the indifference charge for each year. The utilities shall file an advice letter prior to the end of each year or update their testimony in their Energy Resource Recovery Account (ERRA) proceedings to reflect the applicable CRS indifference charge for the subsequent year. The

utilities shall produce the data required as set forth in Appendix 2 for calculating DWR charges.

7. The ongoing CTC figure adopted on an annual basis in PG&E's ERRRA proceeding will be used in conjunction with the CRS indifference charge calculation such that the DWR power charge component of CRS for direct access (DA) customers not exempt from that charge will be the residual of the indifference charge less the ongoing CTC. The PCIA component of DA CRS may be a negative number in those instances in which ongoing competition transition charge (CTC) is larger than the indifference charge, so that overall indifference is maintained.

8. Once the DA CRS undercollection balance is fully paid off, the overall indifference charge shall not be permitted to be a negative number. Negative amounts will not be carried forward to a future year.

9. In the event the benchmark in a given year exceeds the level of a utility's total portfolio power cost for that year, and to the extent there remains a DA CRS undercollection balance for such utility, the negative indifference charge shall be reflected in calculating the accruals to the undercollection balance for such year. In no event shall such a negative indifference charge result in any net payment to customers who have left utility service. However, any accumulated negative indifference amount shall continue to be tracked, and applied to any future positive indifference amounts that may accrue in later years of the applicability of the DA CRS.

10. SCE shall track accruals to the CRS undercollection balance and shall file an advice letter in anticipation of such undercollection balance reaching zero to reduce the CRS to the level dictated by the remaining individual CRS elements.

11. Since PG&E's CRS undercollection is deemed to reach zero as of June 30, 2006, PG&E will not be required to track further the CRS undercollection balance thereafter.

12. On July 1, 2006, the DA CRS undercollection balance for PG&E DA customers will be deemed to be paid down to zero.

13. Effective within 30 days from the effective date of this decision, PG&E shall file an advice letter to remove the 2.7¢/kWh cap from its CRS tariff beginning September 1, 2006. The components of the CRS shall thereafter be calculated separately. The DWR bond charge, the Energy Cost Recovery Amount rate, and the ongoing CTC will not be changed on that date, however, nor will the basis for the calculation of the Franchise Fee Surcharge currently paid by DA customers. PG&E shall apply interest at the applicable 3-month commercial paper rate for the effects of CRS revenues received during July and August 2006.

14. For SCE, the 2.7¢/kWh cap shall remain in effect until the CRS undercollection is paid down to zero, currently estimated to occur by the end of 2008.

15. If the Commission decision in an IOU's general rate case or similar base revenue requirement proceeding changes the IOU's generation revenue requirement by more than 2% in mid year, the IOU shall promptly file an advice letter to update the DA CRS to reflect that change in generation base revenue requirement.

16. Within 30 days after the effective date of this order, each of the IOUs shall file an advice letter to revise the DWR power charge component, currently identified separately on direct access non-exempt customers' bills, to be renamed

the Power Charge Indifference Adjustment (PCIA) charge. The tariff revisions to implement the PCIA shall be subject to the following provisions:

- a. The PCIA charge shall preserve the indifference concept adopted in Decision (D.) 02-11-022 for those direct access customers who pay the DWR power charge component of DA CRS.
- b. The PCIA charge shall recover an amount to reflect the franchise fees associated with the DWR revenues collected from direct access customers for the DWR bond charge and the DWR power charge.
- c. The cost responsibility under the sum of the ongoing CTC and the PCIA charge for direct access customers who pay the DWR power charge component of DA CRS shall equal their responsibility under the indifference charge concept, plus for PG&E, an amount to reflect the franchise fees associated with the DWR revenues collected from direct access customers for the DWR bond charge and the DWR power charge. Once the CRS undercollection is paid, the overall indifference charge shall not be permitted to be a negative number. However, any accumulated negative indifference amount shall continue to be tracked and applied to any future positive indifference amounts that may accrue in later years of the applicability of the DA CRS.
- d. The revenue requirement for the PCIA charge is the difference, positive or negative, between direct access non-exempt customers' share of the indifference amount and these customers' share of the ongoing CTC revenue requirement, plus for PG&E, the amount necessary to reflect the franchise fees associated with the DWR revenues collected from direct access customers for the DWR bond charge and the DWR power charge component of DA CRS. For PG&E, no amount for franchise fees associated with DWR revenues will be assessed on direct access customers who pay the DWR bond charge, but do not pay the DWR power charge component of the DA CRS.

- e. If direct access non-exempt customers' share of the indifference amount exceeds these customers' share of the ongoing CTC revenue requirement, then the difference is these customers' DWR power cost obligation. The PCIA charge is positive, and has the effect of decreasing bundled customers' DWR remittance rate, and therefore, for PG&E only, of decreasing bundled customers' Power Charge Collection Balancing Account rate.
- f. If direct access non-exempt customers' share of the indifference amount is less than these customers' share of the ongoing CTC revenue requirement, then these customers' DWR power cost obligation is zero. The PCIA charge is negative, and has the effect of increasing bundled customers' ERRA costs (for PG&E) or URG rates (for SCE). The PCIA charge (including DWR franchise fees) will be set in proportion to the ongoing CTC.
- g. The 2006 DWR revenue requirement for the determination of the indifference amount shall be the amount adopted in the 2006 DWR revenue requirement decision, D.05-12-010. The 2006 revenue requirement for old world resources is the amount adopted in the utilities' 2006 ERRA proceedings and/or in the most recent general base revenue requirement proceeding. The sales forecast used to determine the direct access non-exempt customers' share of these costs will be the sales forecast presented in the utilities' 2006 ERRA proceedings, as modified in the 2006 Annual Electric Tue-Up for PG&E. If the 2006 DWR revenue requirement or utilities' 2006 ERRA/Ongoing CTC revenue requirement is modified, then the calculations described above shall be modified to reflect such changes.
- h. The market benchmark used to determine the direct access non-exempt customers' share of PCIA costs is \$90.12/MWh (\$95.52 at the meter) for PG&E and \$95.17/MWh (\$100.22 at the meter) for SCE in 2006. These benchmarks represent the 30-day average, over the period from November 15, 2005 to December 15, 2005, of 12 month forward prices for 2006 at North Path 15 and

South Path 15, respectively, to which is added a “resource adequacy” amount of \$4/MWh for PG&E and \$8/MWh for SCE. The average PCIA charge for 2006 for PG&E is negative 0.306¢ per kilowatt per hour (kWh) and for SCE is negative 1.805¢ per kWh. This negative 1.805¢ may be affected by the treatment of administrative costs in Edison’s Test-Year 2006 general rate case.

17. In its advice letter filing in compliance with this decision, PG&E shall adjust bundled customer power charges to reflect the overpayment of the CRS loan by noncore bundled customers in the amount of \$325 million, to be recovered from core bundled service customers and credited against noncore bundled customers rates over a 30-month period as directed in the following ordering paragraph. The corresponding annualized increase to core bundled customers is \$130 million with an equivalent decrease to noncore bundled customer by the same amount.

18. Effective September 1, 2006, January 1, 2007, January 1, 2008, and January 1, 2009, respectively, adjustments shall be made to the allocation among customer groups by increasing or decreasing energy related (*i.e.*, per kWh) generation rate components by an equal cents per kWh. In the residential class, consistent with current practice, the increase will be allocated by proportional increases to the Tier 3, Tier 4, and Tier 5 surcharges such that the revenue allocated to the residential class is fully collected from the residential class. On March 1, 2009, this differential adjustment to core and noncore bundled rates shall be discontinued.

19. The Municipal Departing Load (MDL) CRS obligation shall be determined on a prospective basis in a manner consistent with the findings and directives in this decision, as set forth in the findings of fact and conclusions of law above.



20. The protocols for administering MDL CRS transferred load exemptions as set forth in Appendix 4 are hereby adopted.

21. The Commission's Energy Division shall convene a subsequent meeting of the Working Group within 30 days of the effective date of decision for the purpose of seeking consensus on the calculation of the Market Benchmark for 2007 consistent with the principles of this order, and also to finalize the calculation of MDL CRS accrual charges and obligations consistent with this order, and to develop protocols for new load CRS exemptions.

22. Any prospective CRS issues concerning DA obligations shall be addressed in each IOU's respective ERRA proceeding or by advice letter, as appropriate.

23. Rulemaking 02-01-011 is closed.

This order is effective today.

Dated July 20, 2006, at San Francisco, California.

MICHAEL R. PEEVEY  
President  
GEOFFREY F. BROWN  
DIAN M. GRUENEICH  
JOHN A. BOHN  
RACHELLE B. CHONG  
Commissioners